Optimizing Technologies for Detecting Natural Fractures in the Tight Sands of the Rulison Field, Piceance Basin

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SUMMARY

Economically viable natural gas production from the low permeability Mesaverde Formation in the Piceance Basin, Colorado requires the presence of an intense set of open natural fractures. Establishing the regional presence and specific location of such natural fractures is the highest priority exploration goal in the Piceance and other western U.S. tight, gas-centered basins.

Recently, Advanced Resources International, Inc. (ARI) completed a field program at Rulison Field, Piceance Basin, to test and demonstrate the use of advanced seismic methods to locate and characterize natural fractures. This project, conducted jointly with Barrett Resources and supported by the USDOE/FETC, began with a comprehensive review of the tectonic history, state of stress and fracture genesis of the basin. A high resolution aeromagnetic survey, interpreted satellite and SLAR imagery, and 400 line miles of 2-D seismic provided the foundation for the structural interpretation. The central feature of the program was the 4.5 square mile multi-azimuth 3-D seismic P-wave survey to locate natural fracture anomalies. The interpreted seismic attributes are being tested against a control data set of 27 wells. Additional wells are currently being drilled at Rulison, on close 40 acre spacings, to establish the productivity from the seismically observed fracture anomalies. A similar regional prospecting and seismic program is being considered for another part of the basin.

The preliminary results indicate that detailed mapping of fault geometries and use of azimuthally defined seismic attributes exhibit close correlation with high productivity gas wells. The performance of the ten new wells, being drilled in the seismic grid in late 1996 and early 1997, will help demonstrate the reliability of this natural fracture detection and mapping technology.

BACKGROUND

The purpose of the DOE/FETC supported R&D project being conducted by Advanced Resources International, Inc. is:

> *"Optimize geological and geophysical techniques for economically detecting, mapping and evaluating naturally fractured tight gas reservoirs."*

The technical and geologic rationale for the natural fracture detection R&D project stems from the following three conditions:

- Significant areas of natural fracture enhanced permeability exist in extensive low-permeability, gas saturated basins,
- The use of random drilling and shear wave seismic are high cost approaches for locating these naturally fractured areas, and
- Lower cost methods utilizing satellite imagery, aeromagnetics and modified P-wave seismic (applied in an integrated fashion) offer a new, powerful technology for more reliably targeting these naturally fractured "sweet spots."

The R&D project was conducted in four phases encompassing three years. The first phase involved the preparation of the geologic framework for the basin and the selection of the project site. The second phase involved the characterization of the site using multiple geologic and geophysical data sets, including satellite imagery, high resolution aeromagnetics and interpretation of existing 2-D seismic data for identifying areas that may be naturally fractured. The third phase involved the acquisition and interpretation of a 3-D azimuthally-dependent seismic data for mapping naturally fractured areas. The final phase involved the correlation of the aeromagnetic and seismic data with actual well performance and the preparation of the project summaries and reports.

PROJECT SETTING

The R&D project is located in the Rulison Field, in the southern portion of the Piceance Basin, Colorado. The Piceance Basin is a complex, gas centered basin formed by Laramide tectonism during late Cretaceous through Paleocene time, **Figure 1**. The basin is bounded on the north by the Axial Basin anticline, on the east by the White River Uplift, and on the south by the San Juan volcanics and Uncompahgre Uplift. It is separated from the Uinta Basin to the west by the Douglas Creek Arch. The Piceance Basin is highly asymmetrical with a gently dipping western flank and a steeply dipping eastern flank, known as the Grand Hogback Monocline. Deposition of the Mesaverde Group sands and shales mostly predated Laramide tectonism. The Mesaverde Group is further divided into the regressive deposits of the Iles Formation (Corcoran and Cozzette sandstones) and the overlying massively stacked, lenticular nonmarine Williams Fork Formation, **Figure 2**.

The Williams Fork Formation in the southern Piceance Basin is a 3,000 to 4,000 foot thick package of tight sands, shales and coals. The two stratigraphic intervals of interest are: (1) the lower Williams Fork interval of coals and sands called the Cameo Formation locally that lies on top of the Rollins Sandstone; and (2) the upper Williams Fork interval called the Mesaverde Formation locally with a top at the Cretaceous-Tertiary unconformity. The sands in these two intervals are part of a basin-centered gas trap, with overpressured gas downstructure from more permeable water filled reservoirs. The fluvial sandstones are judged to be pointbar deposits stacked into a composite of meander-belt reservoirs, each 20 to 60 feet thick and 500 to 1,500 feet wide, with considerable internal discontinuities and compartments.

Because of authigenic clays, carbondate cement and quartz overgrowth, the sands have low porosities of 6 to 12% and low matrix permeabilities often below one microdarcy. Areas enhanced by natural fractures have one to two orders of magnitude increases in permeability, as shown by the differences in lab measured matrix permeability and well test reservoir permeability at the DOE/GRI MWX site, **Figure 3**. A series of excellent publications and articles are available on the geologic setting of the Mesaverde Group formations, stemming from the GRI and DOE sponsored work at the MWX test site.[1,2]

Figure 1
Williams Fork Formation, Piceance Basin
Gas Centered, Tight Gas Basin

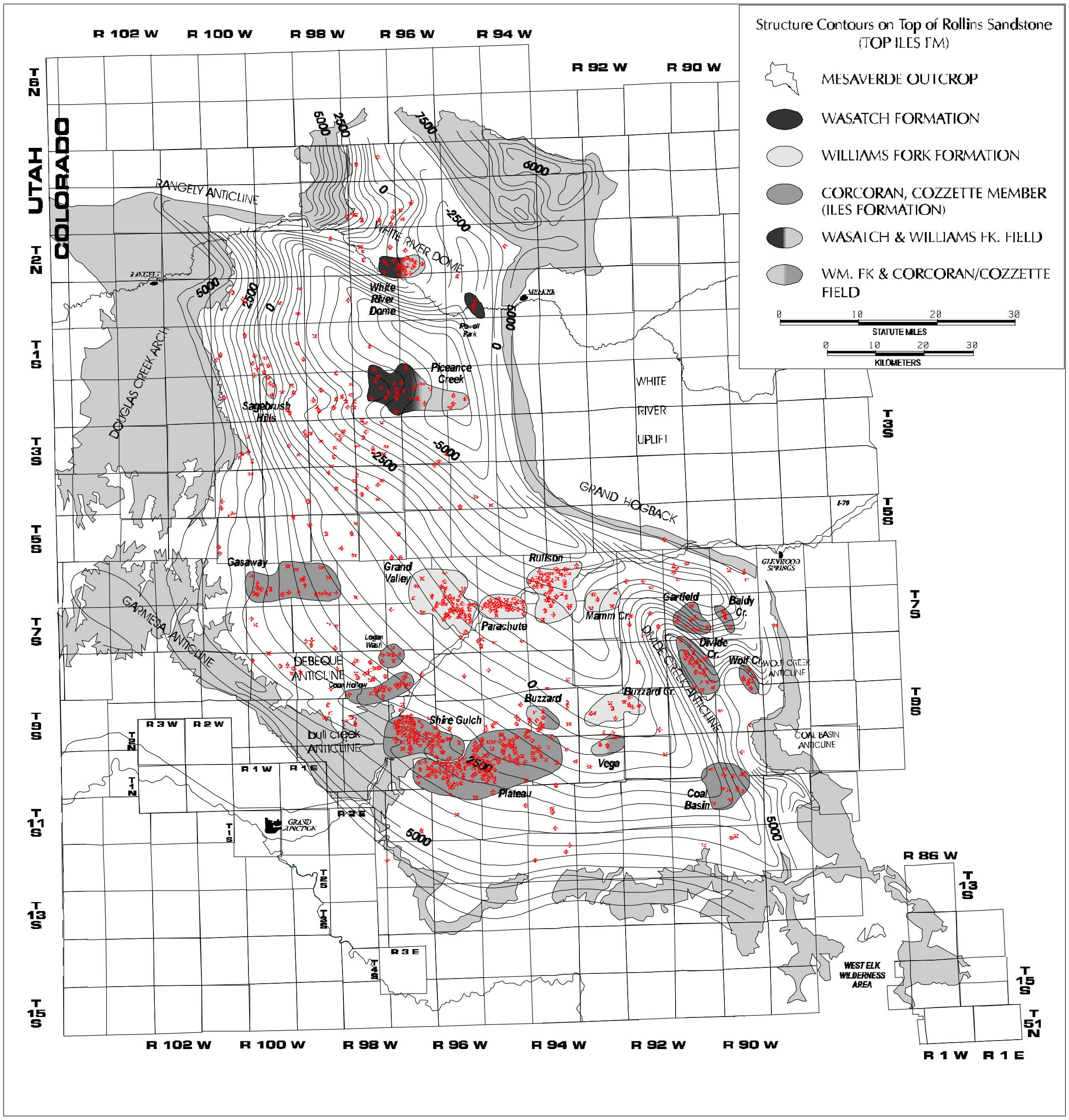
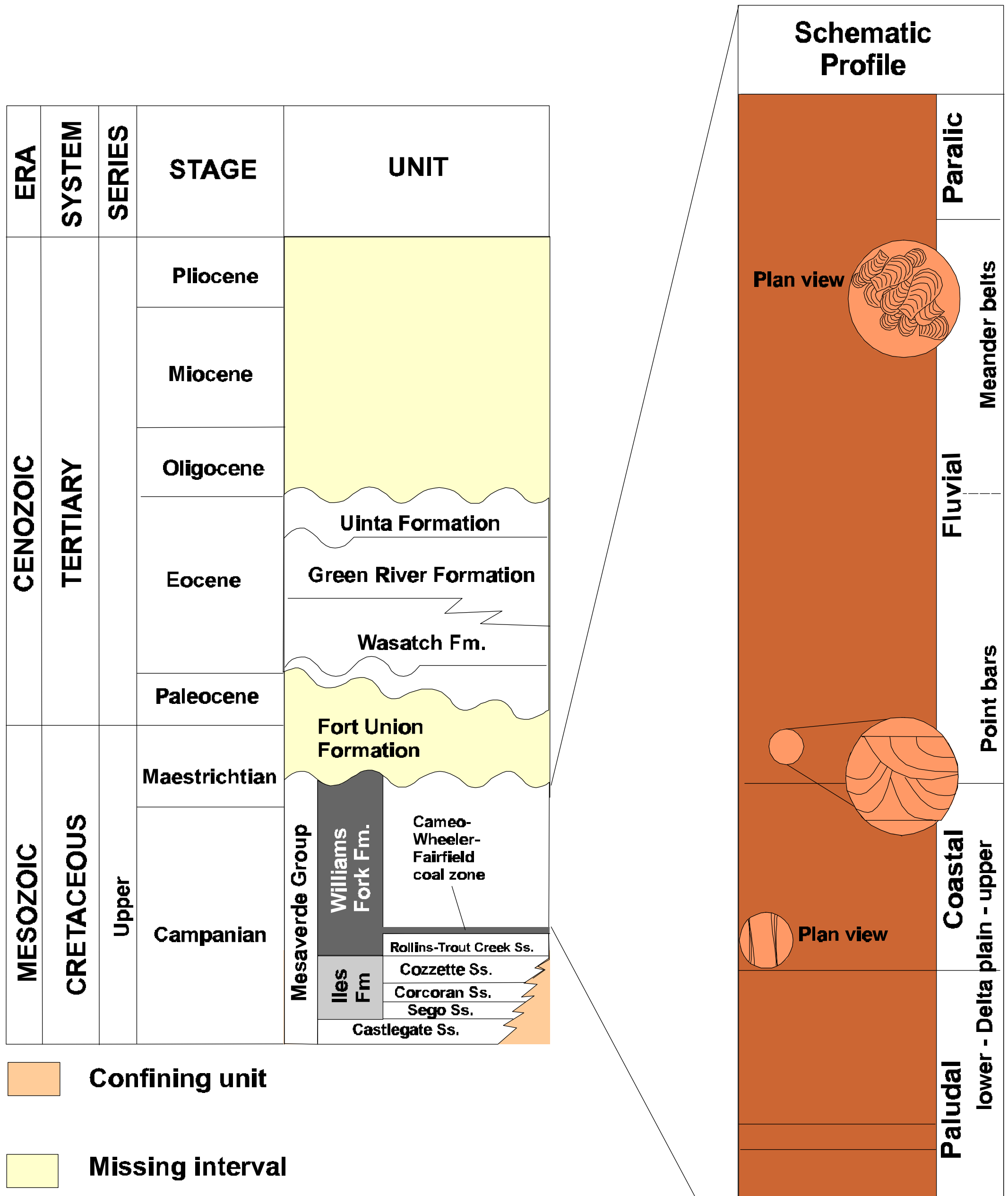


Figure 2
Stratigraphic Column, Depositional Environments and Reservoir Characteristics of the Mesaverde Group



Modified from Tyler and McMurray, 1995 and Lorenz, 1989

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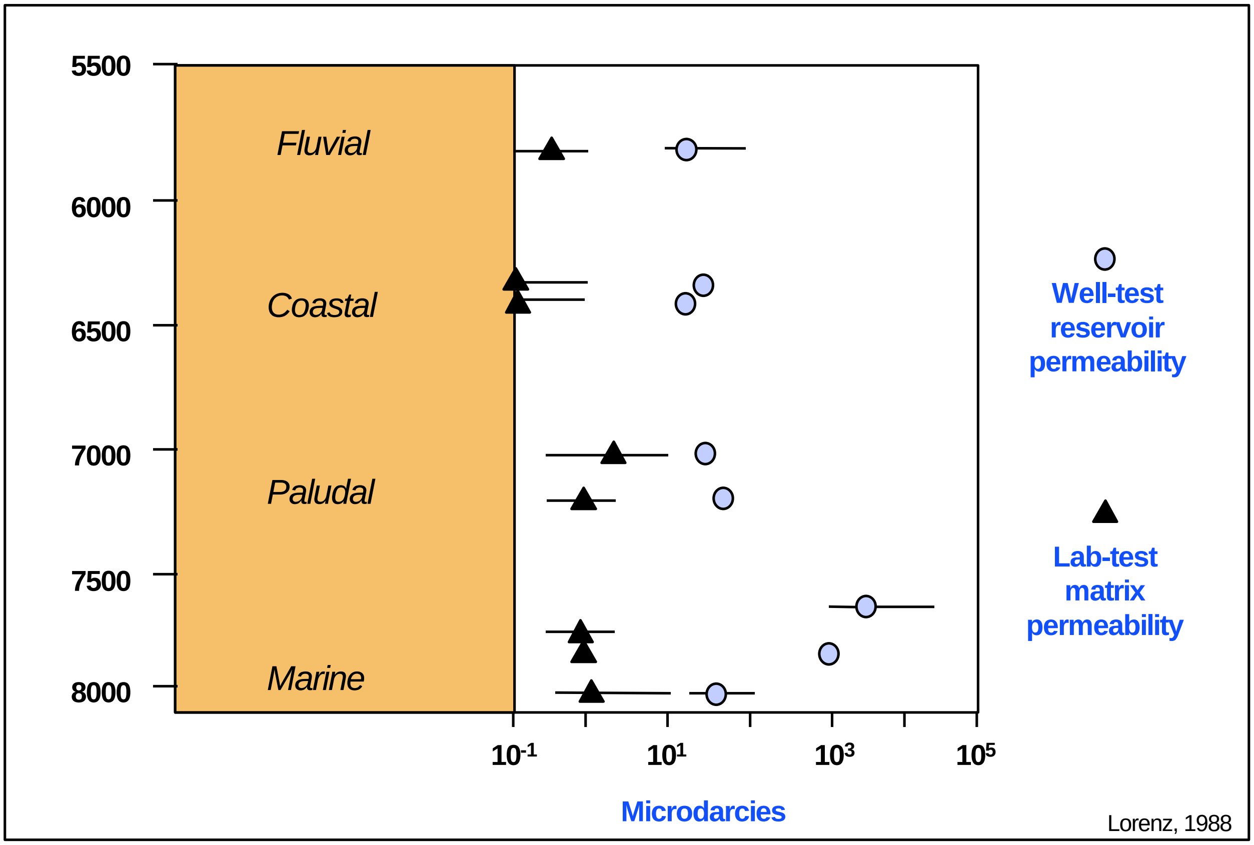
Figure 3
Reservoir & Matrix Permeabilities



Using a recent stratigraphic study of the southern Piceance Basin,[3] advanced well log analysis on 12 key wells (discussed below), and recent reservoir data from operators, Advanced Resources prepared resource estimates for this basin. For the southern basin, these estimates were prepared on a section by section basis and then mapped to show the concentration and distribution of the gas in place. For the northern basin, the gas in place estimates were prepared by first partitioning the basin into three areas and then using log analysis on 4 key wells, mudweight data and geological inferences to provide a regional perspective on the size of the resource.

Based on this, it is estimated that 311 Tcf of gas in place exists in the Williams Fork lenticular sands (plus 75 Tcf of coalbed methane in place in the Cameo and Coal Ridge coals) in the Piceance Basin, with 106 Tcf of the gas in place in the southern portion of the basin. These gas in place estimates are reasonably consistent with other resource studies of this tight gas basin.[4,5]

The Williams Fork lenticular sand formation in the Rulison field area holds a high concentration of gas in place, estimated at 160 Bcf per square mile in the sand plus another 40 Bcf per square mile in the Cameo coals, **Figure 4**. As such, the area represents one of the richest concentration of gas in place in the U.S. and represents a high priority target for development.

TECTONIC EVOLUTION OF THE PICEANCE BASIN

A review of the structural and tectonic evolution of the Piceance Basin indicates that basement faulting, resulting from the extentional tectonics during Precambrian and Pennsylvanian time and from Laramide compressional tectonics, has influenced the structural anisotropy, state of stress and major fault systems in this basin, **Figure 5**. A reactivated paleohorst and SW-NE directed regional shortening produced the dominant regional deformation and structures in the southeastern basin, including the subtle Rulison Anticline. The basin has experienced slight WNW and EW compression from Holocene to present.

Given the structural and depositional history of the basin, the vertical overburden stress appears to be similar in magnitude to the maximum horizontal compressive stress. As a result, fracturing has occurred perpendicular to both the least and the intermediate stress orientations, creating a mix of N30^{o}W, N60^{o}E and N70^o-80^{o}W sub-vertical fracture trends, **Figure 6**.

Figure 4
Original Gas-In-Place
(Mesaverde and Cameo Sands)

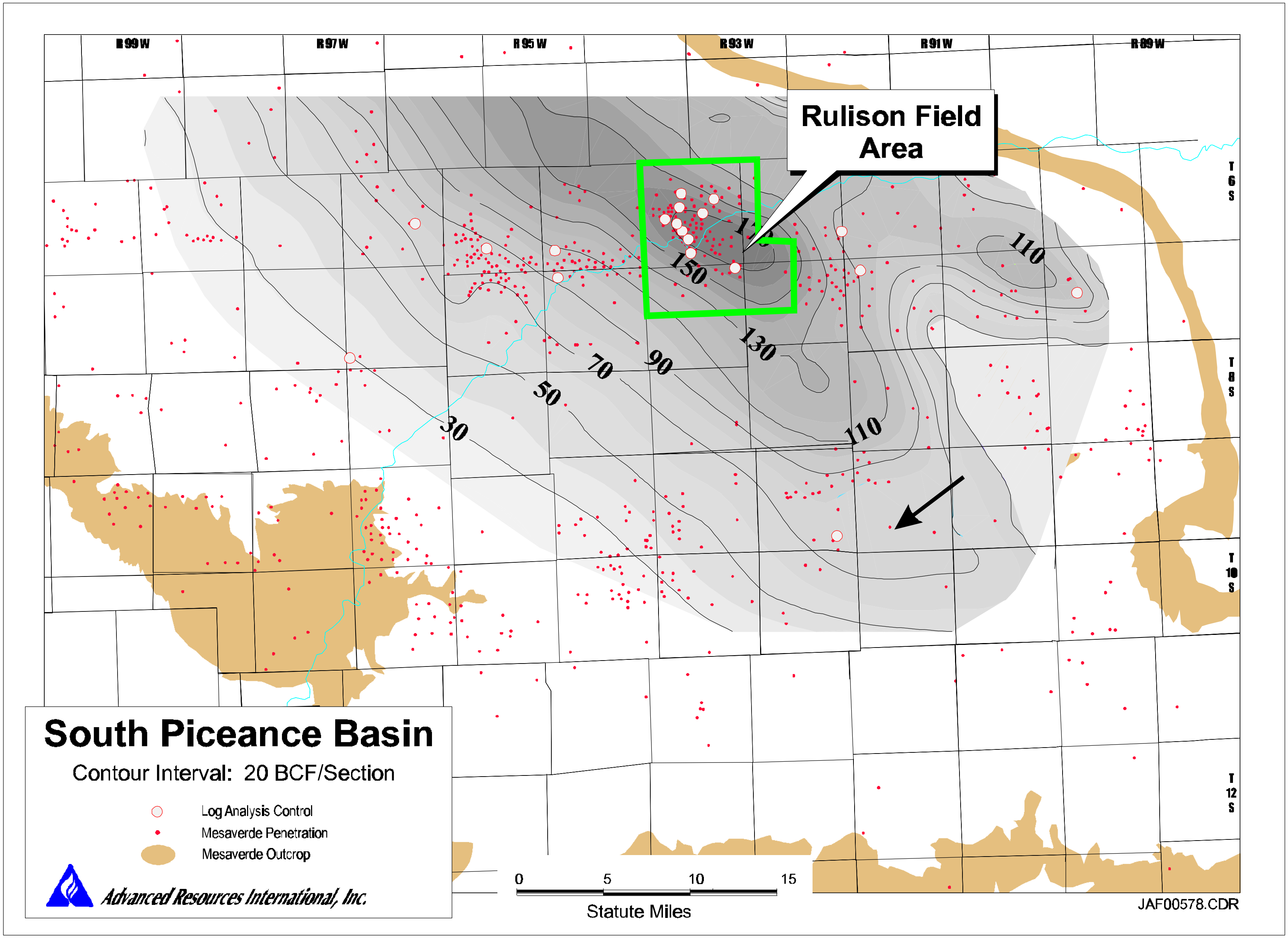


Figure 5
Tectonic History, Rulison Area, Piceance Basin

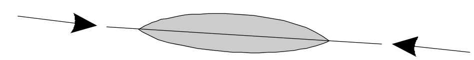
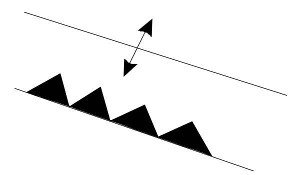
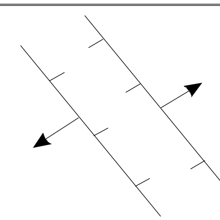
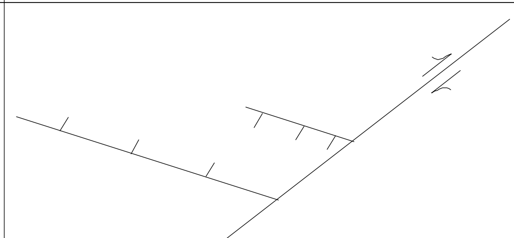
Geologic Age	*Structural Style*	*Schematic*
Miocene to Recent	**Regional Uplift**	 **WNW Maximum Compression**
Cretaceous to Eocene	**Laramide Thrust Faults and Related Folding**	 **SW Directed Shortening**
Pennsylvanian/ Permian	**Faulting and Graben Development**	 **NW Trending Extension**
Precambrian	**Regional Crustal Shearing and Extension**	

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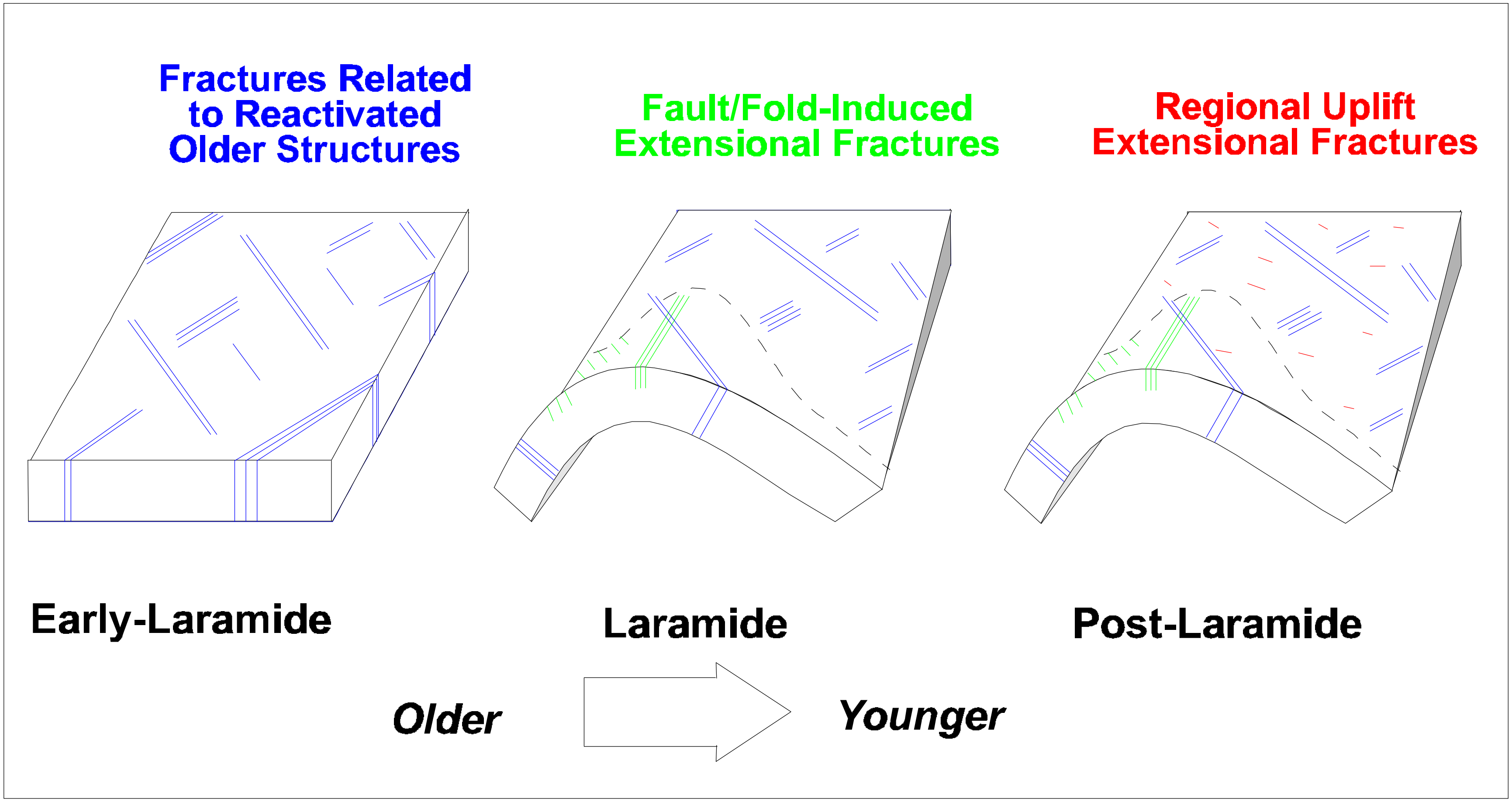
Figure 6
Development of the Major Fractures
in the Rulison Area, Piceance Basin



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INTEGRATED APPROACH TO NATURAL FRACTURE DETECTION

The central premise of the model is that an integrated approach using geological and geophysical methods can be used in a cost-effective manner to locate fractured areas where advanced seismic methods can be utilized, **Figure 7**. The linking of geologic investigations remote imagery analysis, and high resolution aeromagnetics provides higher reliability and confidence to the assessment and a lower cost approach to identification prospects, the location of the seismic survey and the spotting of the exploration wells, **Figure 8**.

HIGH RESOLUTION AEROMAGNETIC SURVEY

The analysis of basement structure and tectonics was performed using a high-resolution aeromagnetic survey, flown for the project by World Geoscience. The close line spacing (400 meters E-W by 1,600 meters N-S) and the low aircraft flight elevation (150 meters above mean terrain) provided high quality data on the shallow basement anomalies important for interpreting faulting and fracturing in this basin. **Table 1** provides the key parameters of the high resolution aeromagnetic survey.

The total magnetic intensity map (RTP-reduced to pole) and three pseudo-depth slice maps were used for interpreting the major basement features and shallow-source anomalies. The aeromagnetically defined features were found to closely correspond to basin structure and the mapped linear trends. Most significant, the NW trending magnetic anomaly identified in and extending through the Rulison Field closely correlates with the high productivity, 2+ Bcf per well fairway, which has recently been extended to the south-east, **Figure 9.**

The incorporation of the high resolution aeromagnetics survey in the project helped demonstrate the value of using a low cost regional reconnaissance method to locate fracture prone, prospective areas prior to employing a more costly seismic program to identify optimum well sites.

Figure 7
Integrated Technologies for Naturally Fractured Tight Gas Exploration and Development

1. **<u>Basin Deposition and Tectonic History</u>: Geologic Framework**

2. **<u>Satellite Imagery</u>: Regional Reconnaissance**

3. **<u>High Resolution Aeromagnetics</u>: Prospect/Trend Definition**

4. **<u>Azimuthal 3D P-Wave Survey</u>: Well Site Selection**

MAP OF S. PICEANCE BASIN

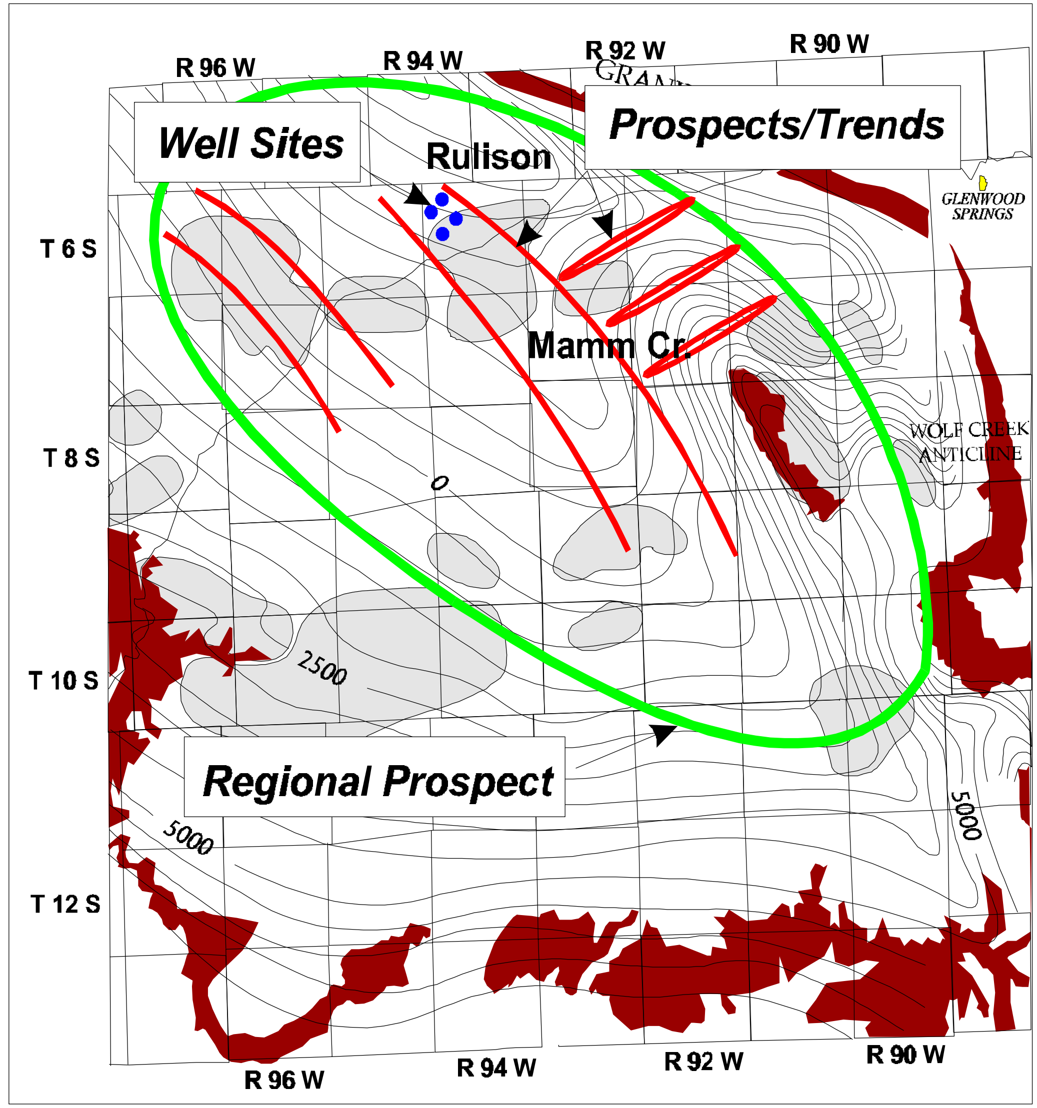

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Figure 8
Integrated Exploration Methodology

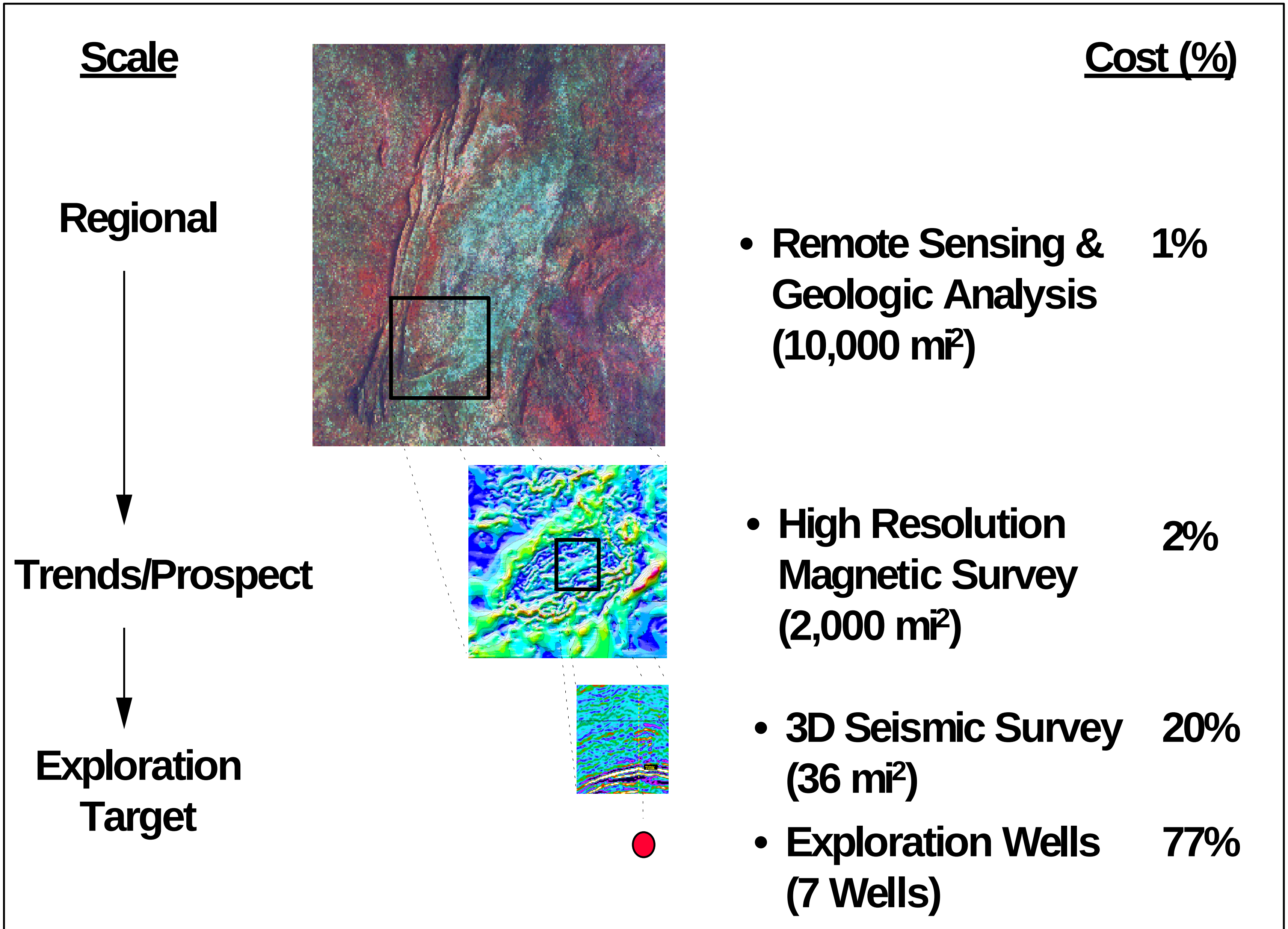

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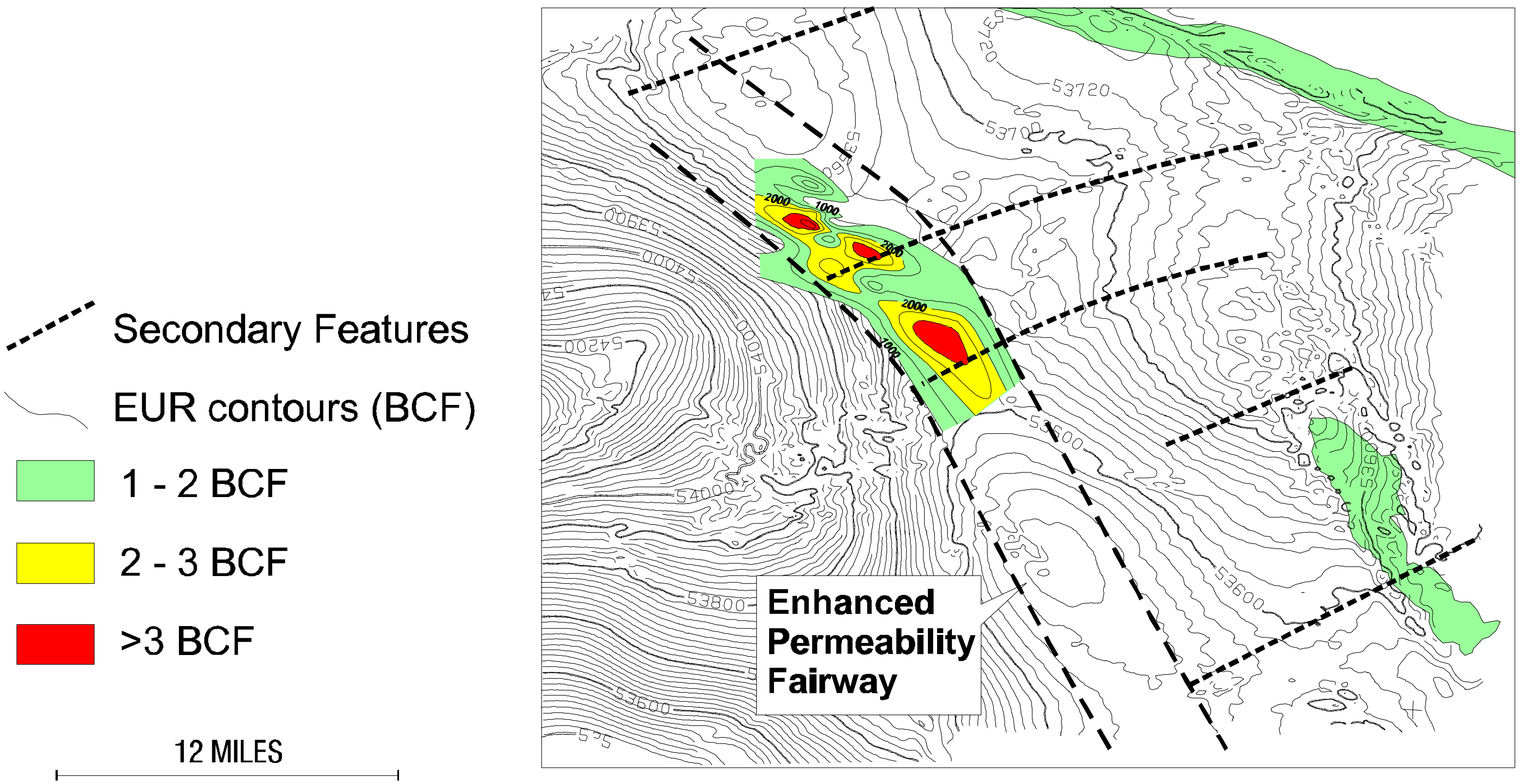
Table 1
High Resolution Aeromagnetic Survey

- **<u>Purpose</u>:**
  1. **Determine relationship between basement features and fracture trends**
  2. **Establish reliability of HRAM for mapping basement features.**

- **<u>Design</u>:**
  1. **Close line spacing (400 m E-W; 1,600 m N-S)**
  2. **Low flight elevation (150 m)**
  3. **Southern Piceance Basin**

- **<u>Findings</u>:**
  1. **Magnetic anomalies are predominately first order NW, and E-W with secondary NE trends.**
  2. **NW magnetic anomalies appear to correspond to production trend and related fracture network.**

Figure 9
High Resolution Total Field Magnetic Intensity, Contoured EUR and Interpreted Enhanced Permeability Fairway



SEISMIC PROGRAM

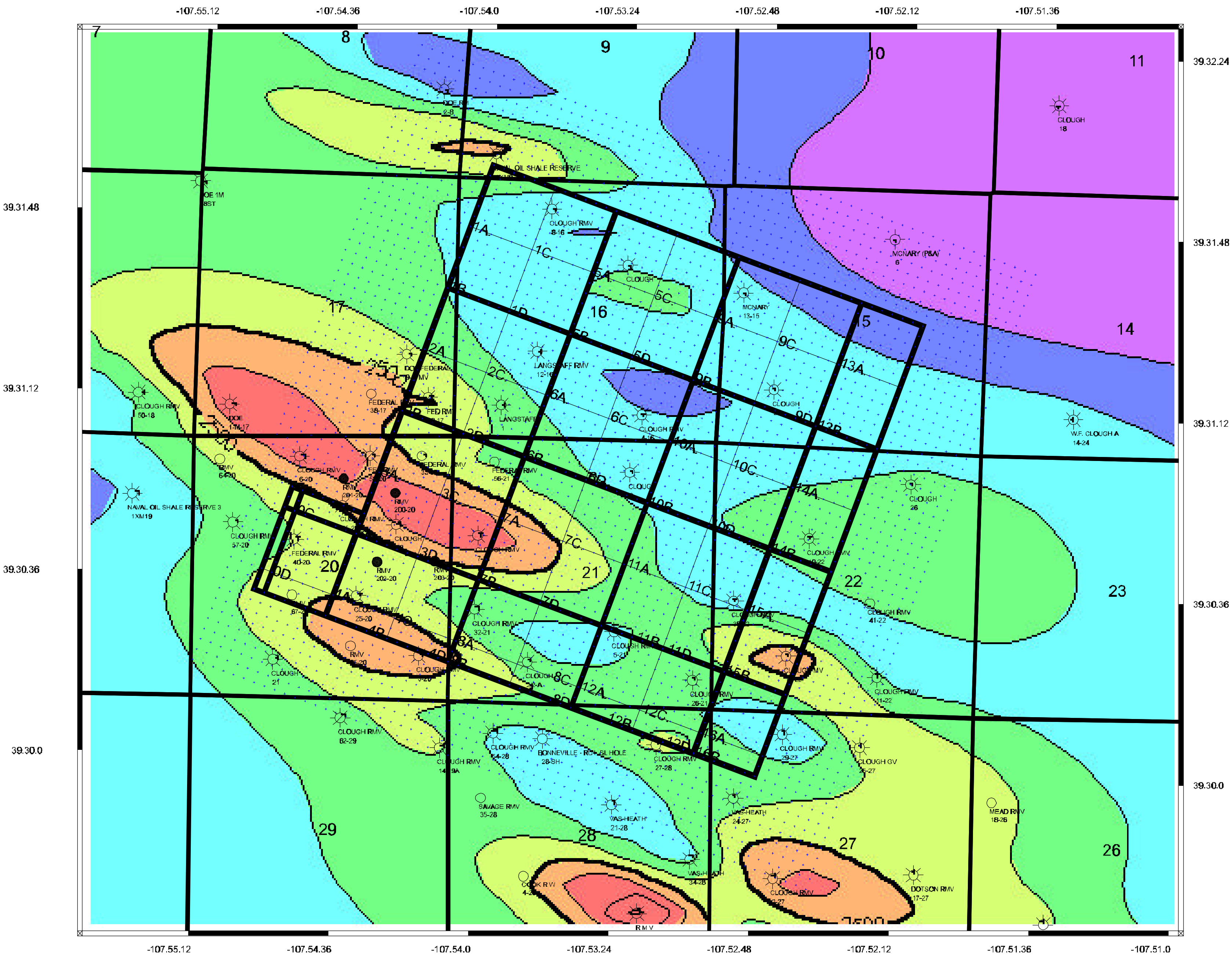
The 3-D seismic survey, conducted by Western Geophysical under contract to the project, covered 4.5 square miles and was located over both the most fractured and the least fractured portions of the Rulison Field, **Figure 10.** The technical requirements for the P-wave reflection data were -- "full-fold, full-offset, full-azimuth." The receiver spacing was 220 feet, leading to a bin size of 110' by 110'. Following processing, the data set was judged to be of very high quality and ready for interpretation.[6] Three independent interpretations are being performed on the seismic data:

- Advanced Resources International, Inc. has interpreted 400 line miles of 2-D seismic for structural control and is interpreting the fault location and geometry from the 3-D data set at Rulison.
- Lynn, Inc. is using azimuthally dependent seismic attributes -- interval velocity, velocity anisotropy and AVO gradients and their differences -- to identify fracture prone areas in the seismic area.
- Western Geophysical is using this high quality seismic data and control wells within the seismic grid to demonstrate their Fractogram™ model.[7]

Seismic Attributes. Results from the analysis of the seismic attributes of velocity and AVO gradient by Lynn, Inc. showed the following:

- Areas of high anisotropy (ratios of >1.04 and <0.96) that might indicate the presence of open, natural fractures.
- Higher and lower AVO gradients that might indicate the higher and lower concentrations of natural gas.
- Areas of the Rulison Field where an overlap exists for the two favorable seismic attributes.

Figure 10
3-D Seismic Grid and EUR Trend, Rulison Field



C A strong positive correlation between favorable seismic attributes and the estimated ultimate recovery (EUR) of the wells in the Rulison Field.

Fault Geometry Mapping. A northwest trending reverse fault is prominently displayed at the Rollins Sandstone time structure map, **Figure 11** and shown to migrate across the field at the Cameo Coal and Middle Williams Fork timestructure maps. **Figure 12 and 13.** In profile, this fault appears nearly vertical until it enters the pay section where the fault plane takes a low angle trajectory. Within the mid pay section, the single fault plane terminates and splays into a wedge of smaller fracture systems characterized by reflector offset, amplitude dimming and generally poor amplitude coherency, **Figures 14, 15 and 16.** The primary fault, NW2, was mapped across the seismically defined area and provided the outlines for the presumed more highly naturally fractured fairway within the Rulison Field, **Figure 17**.

Correlation of Faults and EUR. The 27 wells drilled within the survey were divided into two groups with well selection determined by areas of fault and no or limited fault penetration. Seventeen wells that penetrate the fault zone have EURs that range from 1.6 to 3.3 Bcf with an average of 2.3 Bcf per well. In contrast, the ten wells outside the fault zone have EURs that range between 1.0 Bcf to 1.8 Bcf with an average 1.4 Bcf per well, **Table 2**. Because the pay section and gas in place is relatively uniform in this area, the interpretation is that wells penetrating the fault zone have a higher fracture permeability than those that do not. This pilot study shows that a 3-D survey can be used to accurately locate fracture clusters and fault terminations for preferentially targeting wells with higher reserve potential.

Conclusions. Subtle fault systems can significantly fracture an otherwise tight gas reservoir, creating an economically producible "sweet spot". Even in the case of closely spaced wells or tightly gridded 2-D seismic, these important small displacement faults are difficult to detect and are therefore often overlooked. A 3-D survey provides a powerful technology for identifying structural features that provide the essential fractured permeability pathways necessary for commercial production from low permeability reservoirs. The longer term and more technically challenging goal is to use seismic attributes for detecting open natural fracture systems and to further high-grade the selection of well sites.

Figure 11
Time Structure: Top Rollins SS

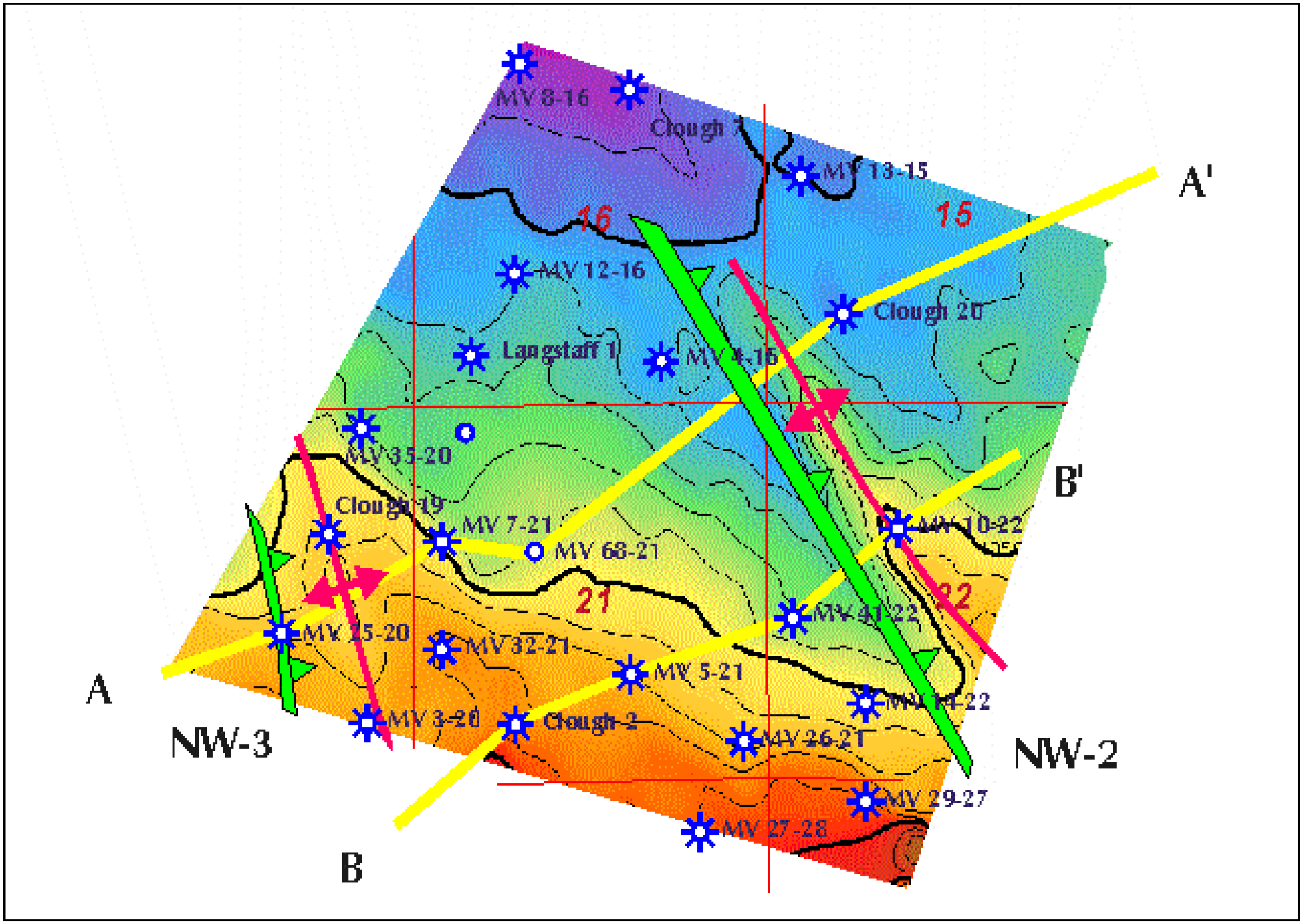


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Figure 12
Time Structure: Top Cameo Coal Group

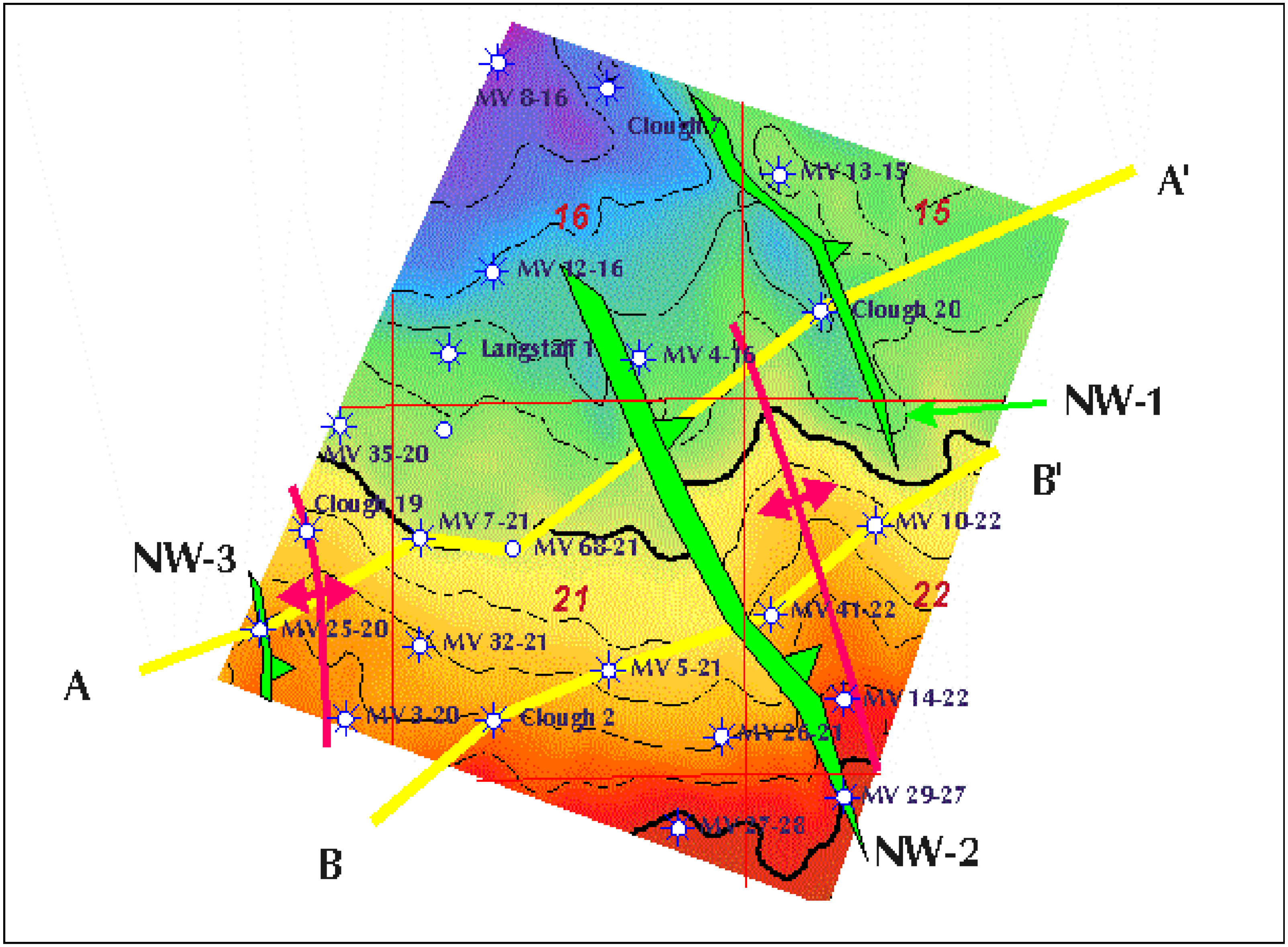

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Figure 13
Time Structure: Middle Williams Fork Formation

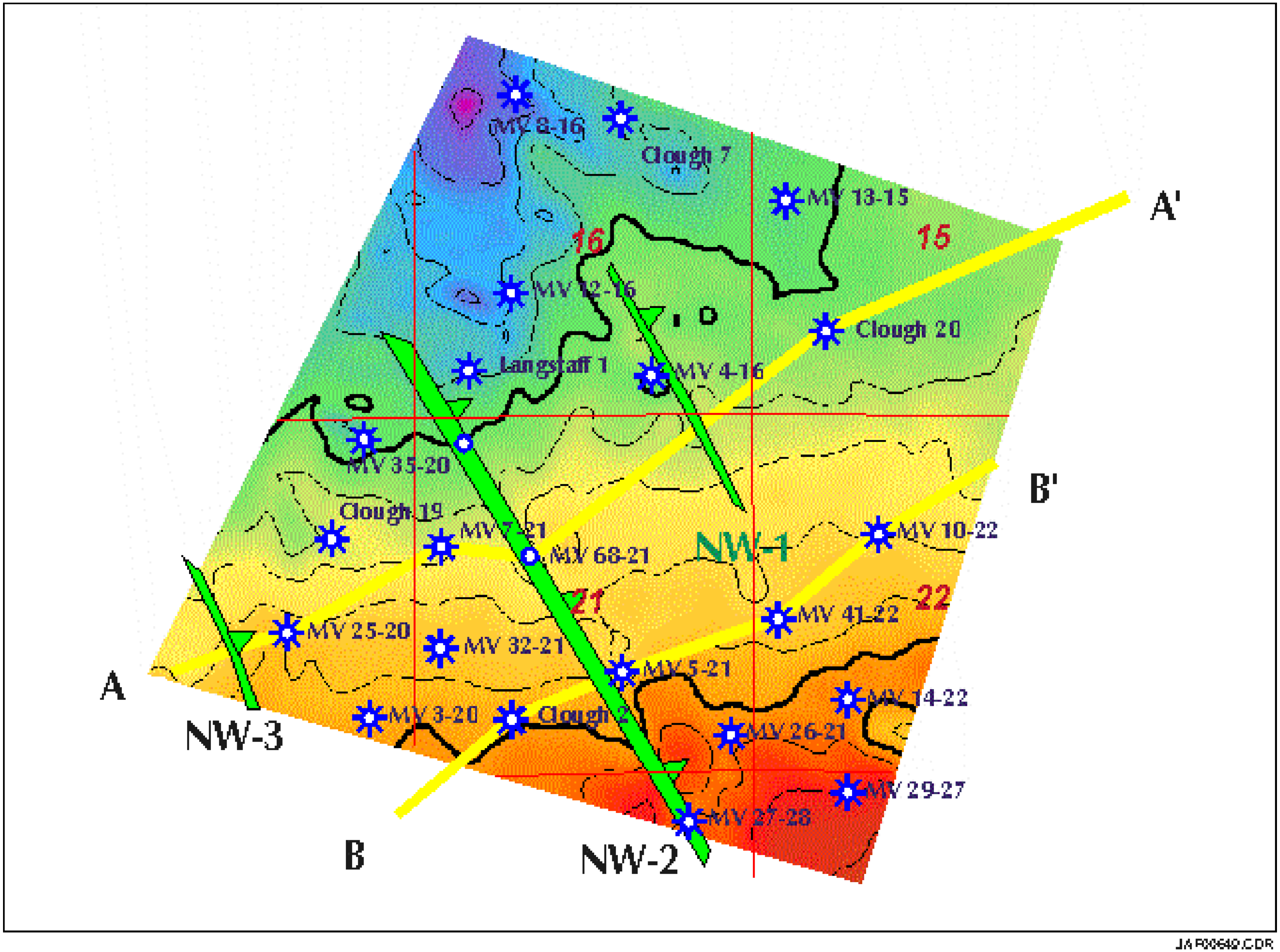

Figure 14
Fault Plane Projection

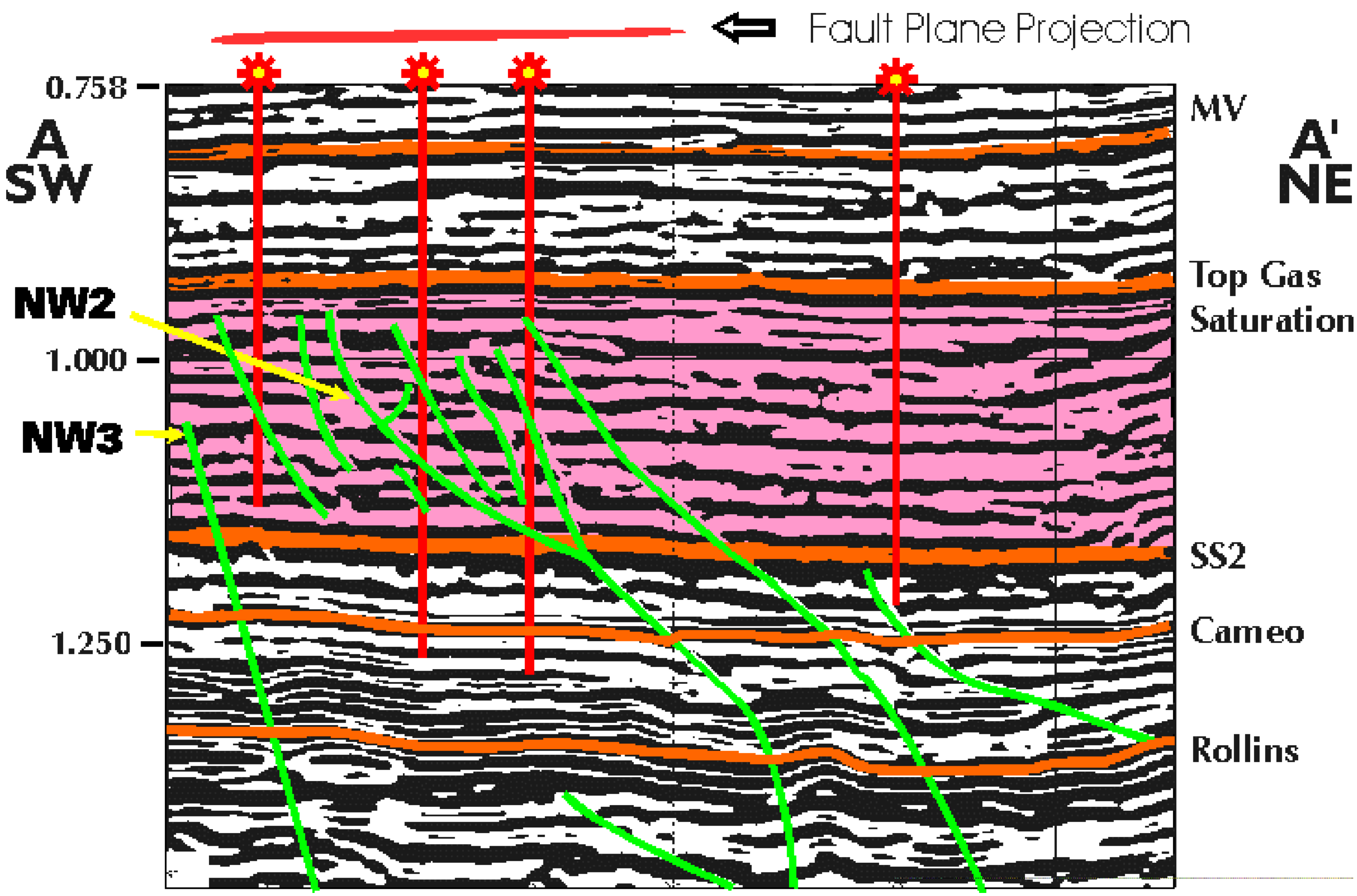

Figure 15
NW2 and NW3 Pay Zone

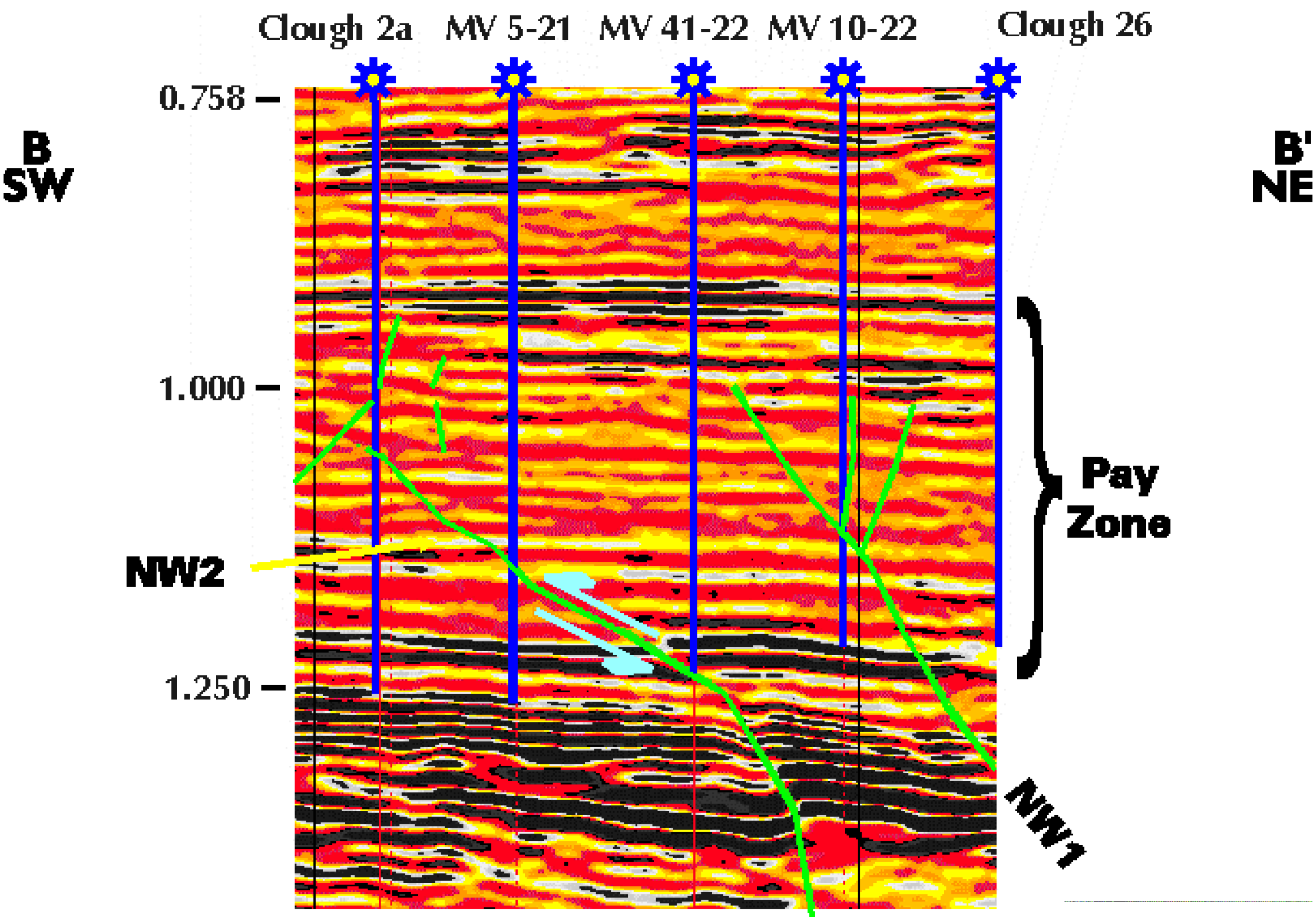

Figure 16
Fault Tip Fracture Cluster, NW3

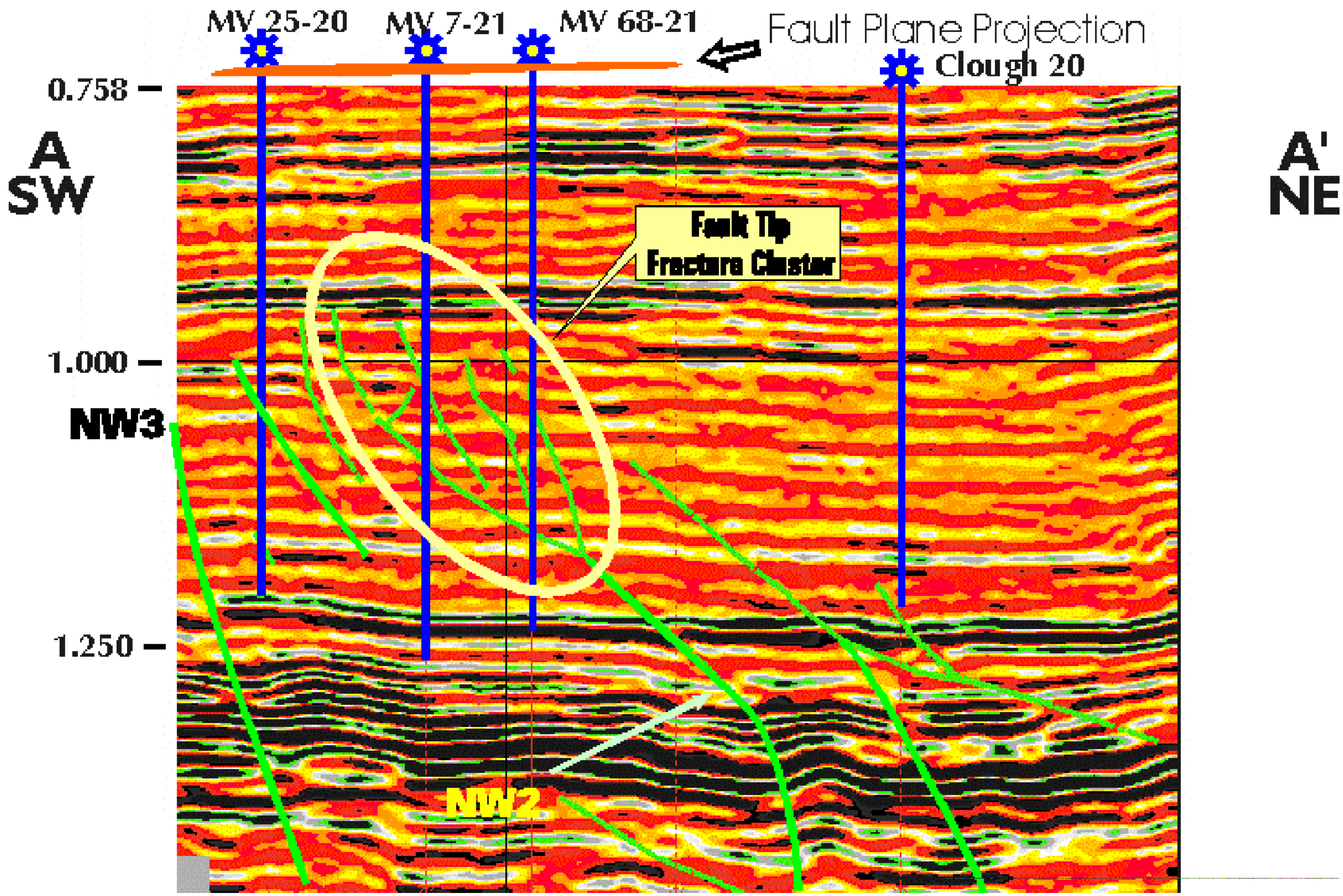

Figure 17
Outline of NW2 Fault Zone, Rulison Field

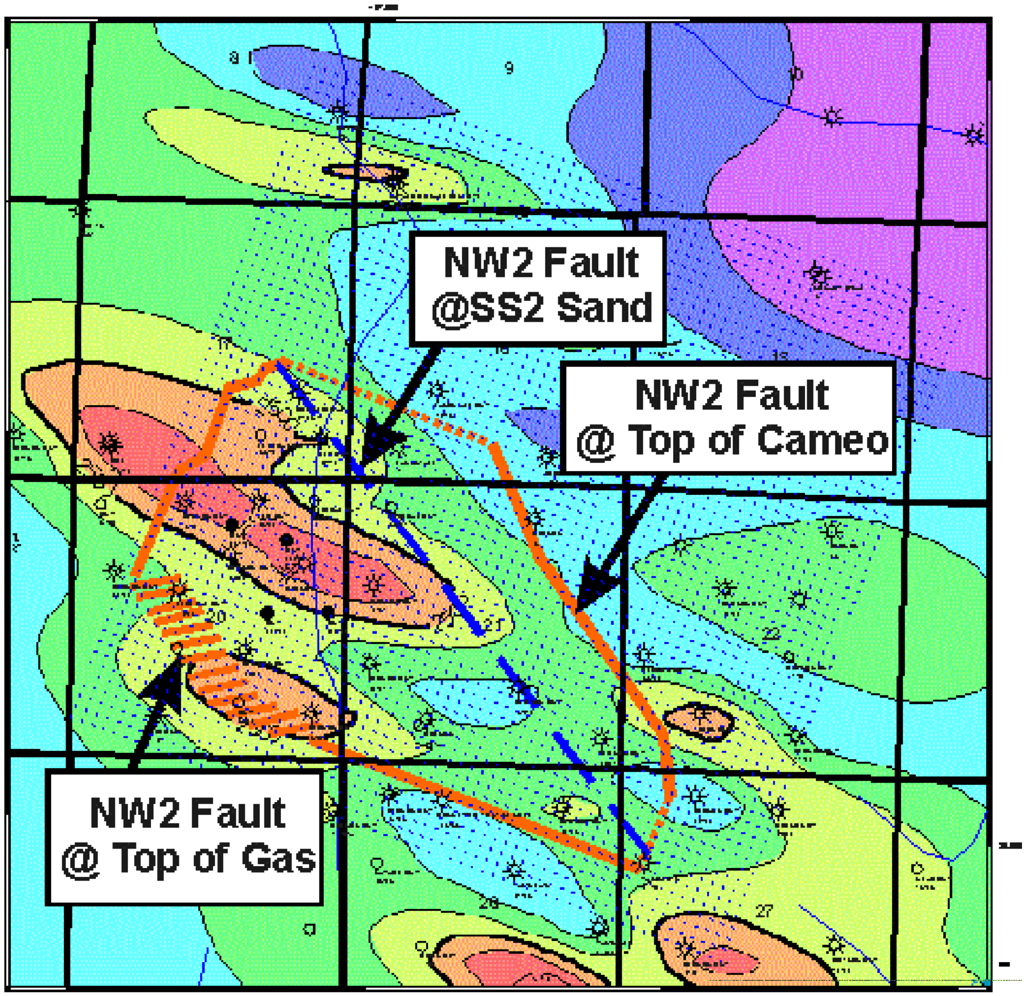

Table 2
Correlation of NW2 Fault Zone With Well Performance

	Inside NW2 Fault Zone	Outside NW2 Fault Zone
No. Wells	17	10
Avg. EUR/Well	2.32 Bcf	1.37 Bcf
Range of EUR/Well*	1.57 to 3.26 Bcf	0.98 to 1.84 Bcf

*After eliminating best and worst wells.

BENEFITS OF NATURAL FRACTURE DETECTION TECHNOLOGY

Successful completion of the natural fracture R&D program would have great benefits for the E&P and natural gas industry. Widespread application of the technology to the Williams Fork Formation in the Piceance Basin would enable industry to more efficiently target the naturally fractured, higher productivity areas. This would:

- Add nearly 12 Tcf of low-cost natural gas in the 1,250 square mile southern Piceance Basin Study area, and
- Save the industry over $2.2 billion in well drilling and stimulation costs by enabling the industry to drill many fewer wells to reach the same level of gas reserve additions.

Specifically, the benefits in the Piceance Basin can be derived by optimizing and commercially demonstrating an integrated approach to natural fracture detection technology that would meet the following technical two objectives:

- The technology would enable producers to place 4 out of 5 exploration and development wells into the naturally fractured "higher productivity trends". (The "higher productivity trends" in the southern Piceance Basin are estimated to cover 20% or 250 square miles of the 1,250 square mile gas productive area.)
- The technology could enable the industry to achieve an average of 1 to 1.5 Bcf of gas reserves per $375,000 in well completion and stimulation costs in the Piceance Basin:
  - At Rulison, because of deeper well depth and use of multiple hydraulic stimulations, the target would be 2 to 3 Bcf of gas reserves per well for wells costing $700,000 to $800,000 each.
  - At Mam Creek, because of shallower depths and the use of one to two hydraulic stimulations, the target would be 1 to 1.5 Bcf of gas reserves per well for wells costing $350,000 to $400,000 each.

SUMMARY AND FINDINGS

The project results achieved to date and industry's high interests in improving their exploration and well placement success in tight gas sands have made natural fracture detection optimization a high visibility R&D project. The key project findings to date are:

- Natural fracture detection technology can impact commercial development of tight gas reservoirs more than any other single technology, particularly in a low to moderate gas price future,
- Technical and cost optimization plus repeatable field demonstration are required for timely industry use of this high value technology in low permeability formation, and
- Variability in major geologic/reservoir settings will require modifications and adaptations of the technology to match the specific conditions in the numerous tight gas sand basins of the U.S.

ACKNOWLEDGMENTS

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